WELL CONSTRUCTION, OPERATING, AND PLUGGING DETAILS

Elk Hills 26R Storage Project

Injection Well 373-35R

Facility Information

Facility Name: Elk Hills 26R Storage Project
373-35R

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Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CoP Details_373-35R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – CoP Details_373-35R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – CoP Details_373-35R_V3	3	01/11/23	Revisions made based on questions received from the EPA 01/06/23

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

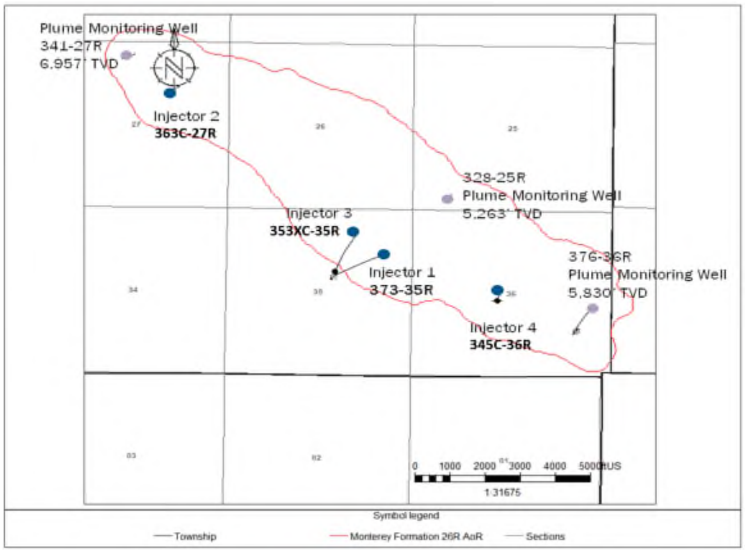


Figure 1: Map showing the location of injection wells and monitoring wells.

Injection well 373-35R is an existing well approved for water injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 4.7 million barrels of water. As part of the UIC approval, California Resources Corporation (CRC) has conducted mechanical integrity (MIT) and standard annular pressure (SAPT) tests to ensure internal and external mechanical integrity.

The *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention

373-35R was drilled in 1982, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors.
2. Although no USDW is present, multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing.
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement, and each casing string was cemented to surface.
4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results. Cement is present throughout the entire CBL logging interval within the Monterey and Reef Ridge formations (from base of 7" casing to ~6600 feet).
5. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted.
6. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous injection conditions.
7. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.

Materials

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion:

- Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Packer – corrosion resistant alloy material or coating and hardened rubber elastomer element material.
- Casing – the standard N-80 and K-55 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.

- Cement- portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Injection and Confining Zones.

Standards

Well materials follow the following standards:

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Casing

The Monterey Formation temperature in 26R is approximately 210 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. The casing will not experience loads from CO_2 injection beyond the designed capability of the well including safety factors. Subsidence has not been observed historically in the areas around the injection wells because of hydrocarbon production, and shallow compression is not anticipated as a concern for casing or cement integrity.

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section. Casing corrosion logging data to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand CO_2 injection load cases expected with the project.

Table 1: Casing Specifications for the 373-35R injector

Name	**Depth Interval (feet)**	**Outside Diameter (inches)**	**Inside Diameter (inches)**	**Weight (lb/ft)**	**Grade (API)**	**Design Coupling (Short or Long Threaded)**	**Thermal Conductivity @ 77°F (BTU/ft hr, °F)**	**Burst Strength (psi)**	**Collapse Strength (psi)**
Conductor	14 – 54	20.000	19.124	94	--	--	2.62	--	--
Surface	14 – 331	13.375	12.715	48	H-40	Short	2.62	1,730	740
Intermediate	14 – 3,006	9.625	8.835	40	K-55	Long	2.62	3,950	2,570

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Long-string	14 – 79 79 – 5,028 5,028 – 6,618 6,618 – 7,988	7.000	6.276 6.366 6.276 6.276	26 23 26 26	N-80 K-55 K-55 N-80	Long	2.62	7,240 4,360 4,980 7,240	5,410 3,270 4,320 5,410

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

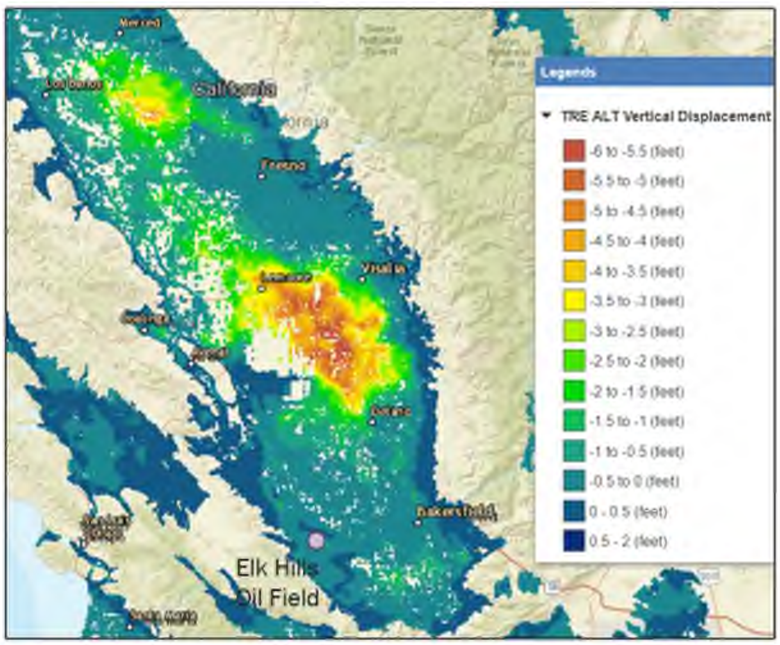


Figure 2: Subsistence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class G portland cement has been used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8” casing string was cemented with returns to surface. The 9-5/8” casing string was cemented with returns to surface. The 7” casing string was cemented in place with Class G portland cement followed with cemented to surface by annular top squeeze. Subsequently, a

CBL was run from 6600' – 7900' and indicates annular isolation throughout and above the Monterey and Reef Ridge formations.

Protection of USDW

No USDW is present within the AoR. However, if USDW is discovered within the AoR in the future, the USDW and all strata overlying the injection zone will be protected by the following:

1. Surface casing is set and cemented to surface within the potential USDW interval, providing multiple protective barriers to ensure protection of the potential USDW above the casing point.
2. The intermediate casing string is set across the base of the potential USDW, and annular cement isolates the potential USDW from the injection string by providing multiple protective barriers to ensure protection of potential USDW.
3. The cement bond log on the 7" casing string indicates annular cement within and above the injection and confining zones, providing adequate isolation of the potential USDW from CO_2 injectate.
4. SAPT tests pressure the well annulus to demonstrate isolation of primary and secondary barriers for the protection of potential USDW. All SAPT's demonstrate that the production casing, tubing, packer, and wellhead have mechanical integrity. Casing/tubing annulus pressure tests to 500 psi for 30 minutes have been acquired through time. SAPT will be acquired before the start of injection and every five years thereafter.
5. If mechanical integrity issues are indicated through monitoring during injection, CTV will perform diagnostics and remediate as necessary.

Tubing and Packer

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. A suitable corrosion-resistant alloy will be installed once the CO_2 stream impurities and impurity concentrations have been determined. The grade identified in Table 2 is anticipated to be acceptable.

Table 2. Tubing Specifications

Name	**Depth Interval (feet)**	**Outside Diameter (inches)**	**Inside Diameter (inches)**	**Weight (lb/ft)**	**Grade (API)**	**Design Coupling (Short or Long Thread)**	**Burst strength (psi)**	**Collapse strength (psi)**
Injection Tubing	7,050	4.50	4.000	11.6	L-80 CRA	Premium	7,780	6,350

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	7,020	30.3	26-32	5.875	4.000

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rates, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan detail the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 373-35R with a surface shut-off valve at the wellhead and not a down-hole device.

Logging and Testing

The following data have been acquired during the initial well construction or during subsequent operations. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be addressed in the Pre-Operational Testing plan document.

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~3,181' feet measured depth (MD) to bottom hole at 8,001 feet MD (Table 4).

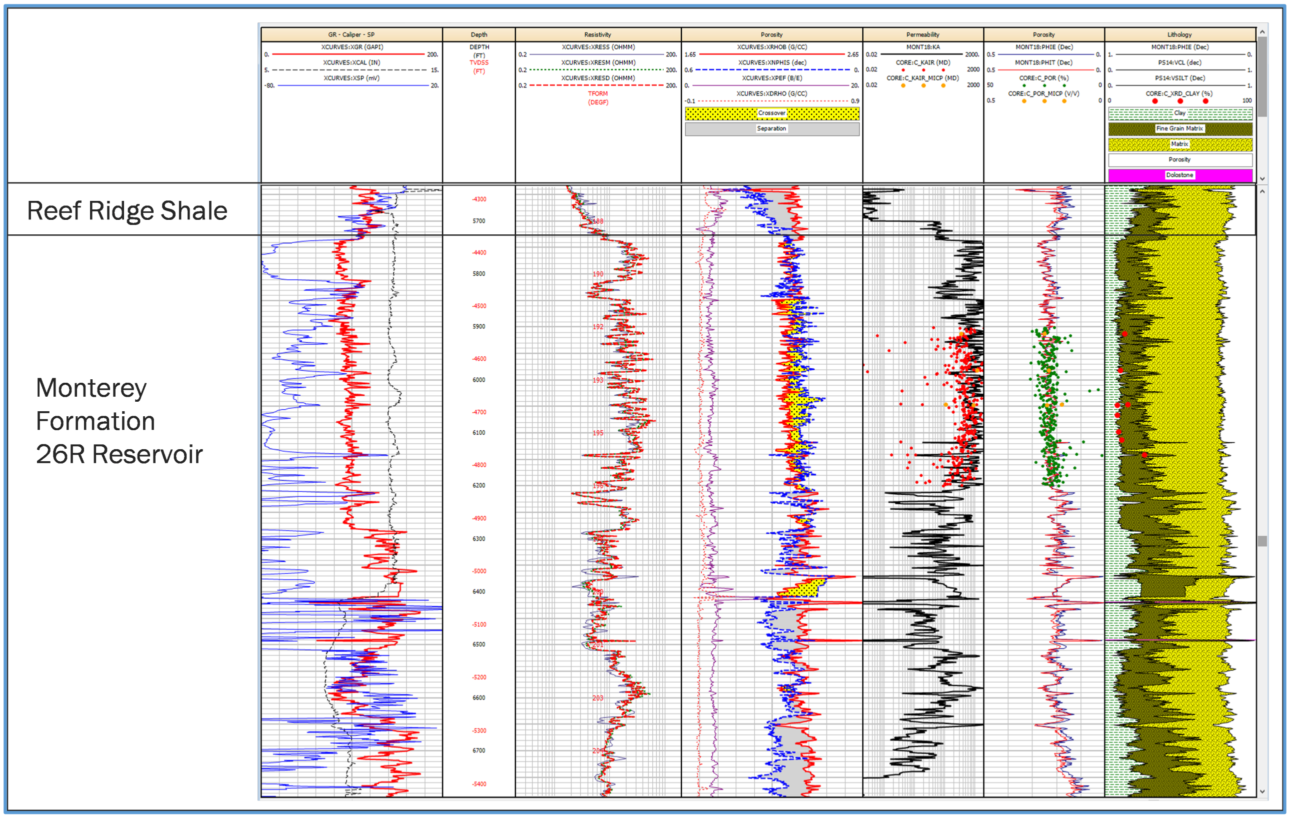
Table 4: Deviation checks during drilling for the 373-35R well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
3,181.00	0.25	250.85	3,180.90		5,344.00	21.5	61.85	5,225.10
3,255.00	2	42.85	3,254.90		5,413.00	21	62.85	5,289.40
3,286.00	3.25	49.85	3,285.90		5,502.00	21.75	61.85	5,372.20
3,349.00	6	52.85	3,348.70		5,660.00	21.5	61.85	5,519.10
3,412.00	9.25	60.85	3,411.10		5,816.00	21.5	62.85	5,664.30
3,442.00	10.75	58.85	3,440.70		5,940.00	21.75	62.85	5,779.50
3,515.00	13.25	55.85	3,512.10		6,056.00	21.25	73.85	5,887.50
3,577.00	14.75	55.85	3,572.20		6,088.00	22	77.85	5,917.30
3,672.00	15.75	59.85	3,663.90		6,163.00	23.75	81.85	5,986.40
3,766.00	17.5	59.85	3,754.00		6,322.00	24	78.85	6,131.80
3,860.00	19	61.85	3,843.20		6,479.00	24	76.85	6,275.20
3,955.00	20.5	63.85	3,932.60		6,542.00	23.75	74.85	6,332.80
4,019.00	21.75	64.85	3,992.30		6,668.00	24.25	72.85	6,447.90
4,152.00	22.25	63.85	4,115.60		6,795.00	24.75	69.85	6,563.50
4,308.00	21.75	64.85	4,260.30		6,859.00	24.75	65.85	6,621.60
4,498.00	21.75	63.85	4,436.80		6,922.00	25	65.85	6,678.80
4,656.00	21.75	62.85	4,583.50		7,016.00	25.75	59.85	6,763.70
4,807.00	21.25	62.85	4,724.00		7,126.00	26.75	55.85	6,862.40
4,996.00	21	62.85	4,900.30		7,265.00	26.5	53.85	6,986.60
5,123.00	20.75	61.85	5,019.00		8,001.00	28.25	50.85	7,640.20
5,246.00	21.25	60.85	5,133.80					

Open Hole Log Analysis

Open-hole wireline log data was acquired prior to installation of 7” casing long string. Figure 1 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), neutron porosity and bulk density in track 3, permeability in track 4, porosity in track 5, and lithology in track 6 (right most).

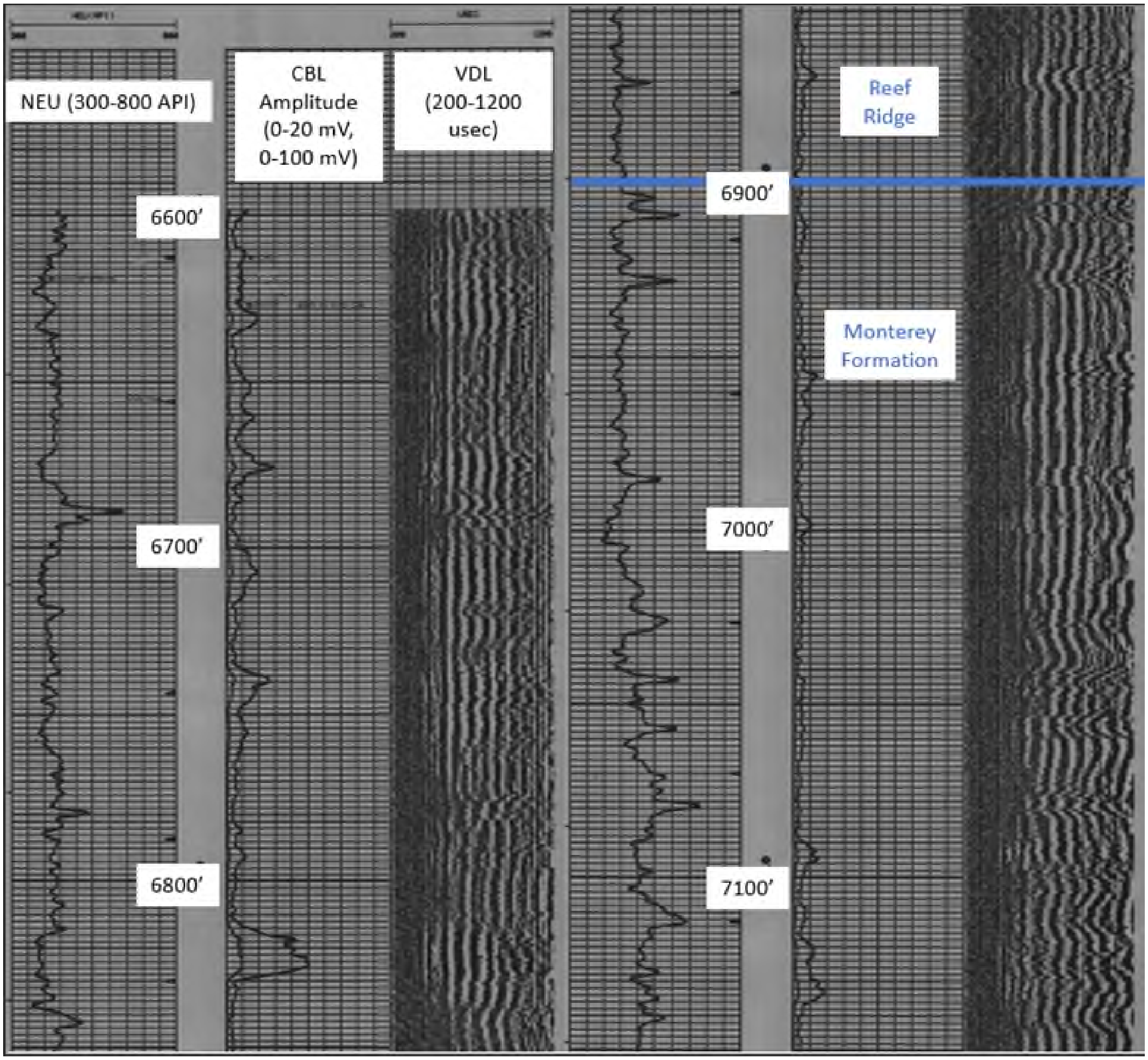
Figure 1: Open-hole well logs for 373-35R before installation of long string.



Cement Evaluation

The cement bond log amplitude and variable density log (VDL) show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 2). Late VDL arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was not logged across the entire 7” casing interval. The top of cement was not observed deeper than 6600’, the top of the cement bond logging interval. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7” casing string during pre-operational testing.

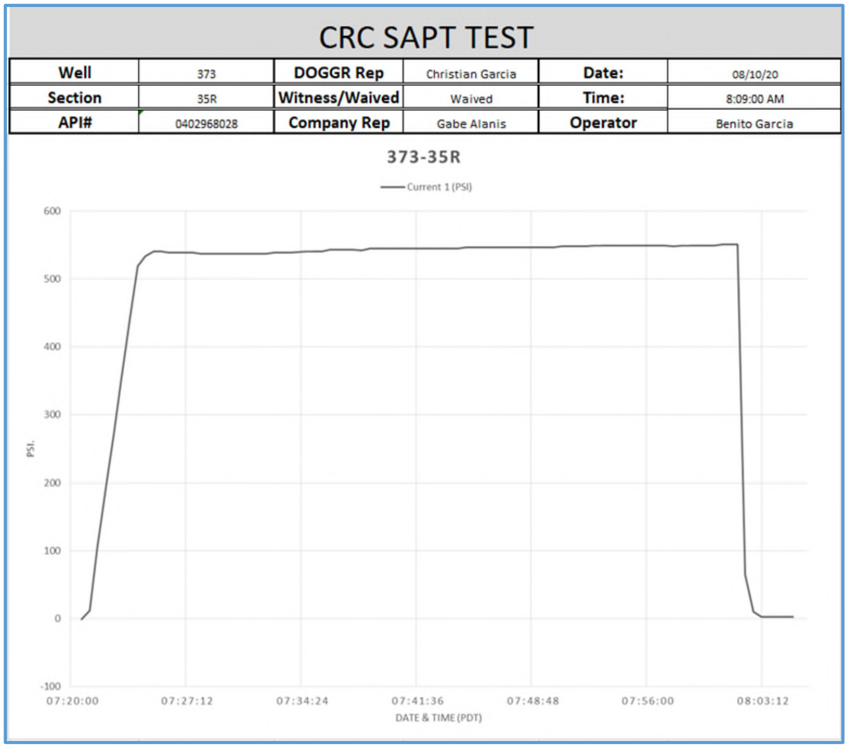
Figure 2: Cement bond log example for 373-35R, after installation of long string casing. The Monterey Formation 26R top is at 6,900 feet.



MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated August 10th, 2020, is displayed in Figure 3. It demonstrates that the annulus can hold pressure more than 500 psi without gain or loss for 30 minutes indicating mechanical integrity of the tubing, casing, and packer as the well is currently configured. SAPT will be conducted again during installation of CRA tubing string prior to injection, and this procedure will be addressed in the Pre-Operational Testing plan document.

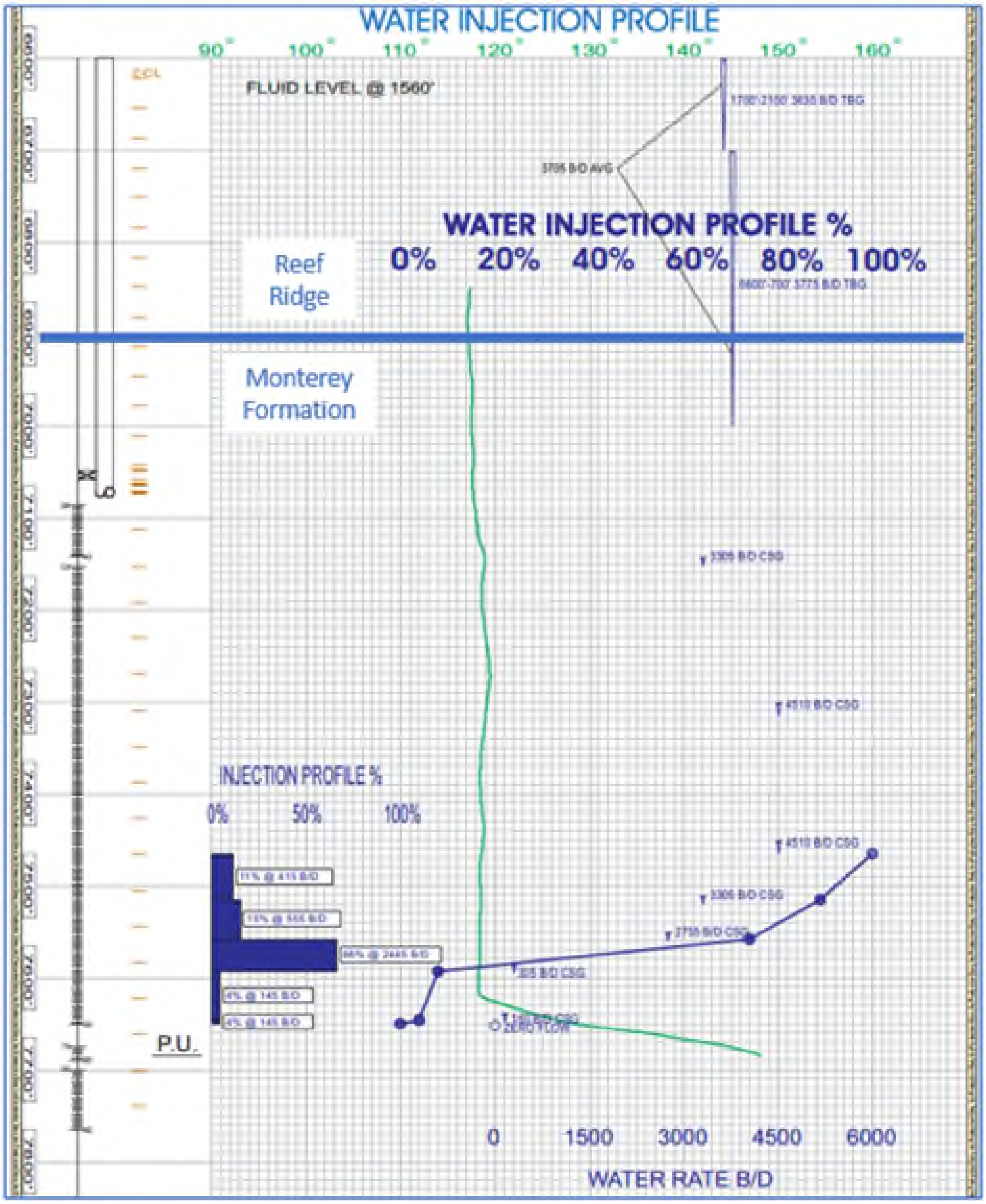
Figure 3: SAPT for 373-35R showing mechanical integrity of the tubing, casing, and packer.



MIT – External: Gas Injection Survey and Temperature Log

The gas injection survey in Figure 4 was acquired on February 26th, 2020. The survey utilizes radioactive tracer to determine injection zone conformance. The interpreted log below indicates valid tubing integrity and no migration of injectate around the top perforation at 7086’ or at the packer at 7050’. The analysis indicates that all injection fluid is entering perforations below ~7450’. The temperature profile in green confirms the results.

Figure 4: Radioactive tracer and temperature survey for well 373-35R showing mechanical integrity of the tubing and isolation of the perforation by the packer.



Planned Well Retrofitting

Prior to first injection, the existing wellbore will be reconfigured for injection through the following procedure:

1. Install and test Blowout Prevention Equipment (BOPE)
2. Pull existing injection tubing and packer
3. Clean out well to Plugback Measure Depth (PBMD)

4. Acquire remaining pre-operational phase data per Att G and T&M docs
5. Install CCS injection tubing, packer, injection tree, and all monitoring equipment per T&M, well schematics.
6. Perform Standard Annular Pressure Test (SAPT) per T&M procedure
7. Perform injectivity test and pressure falloff test
8. Suspend well temporarily for CCS project startup

Well Operation

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a target rate of 18.75 MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been calculated assuming 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection - as the 26R reservoir is depleted in pressure - a surface pressure and down hole injection pressure (calculated at top perforation) of 1014 psi and 2082 psi respectively is expected to be required to achieve the target rate. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface pressure and down hole pressures (calculated at top perforation) required are 1702 psi and 4060 psi respectively.

Based on fracture stimulation data from well 388-26R in the 26R reservoir, the expected fracture gradient is 0.701 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum downhole injection pressure is 4294 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this bottomhole pressure. 40+ years of gas and water injection experience into the Monterey Formation 26R reservoir supports that this is an appropriate and effective operating limit.

The expected pressures over the life of the project are summarized in Table 5.

Table 5: Proposed operational procedures

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.701psi/ft fracture gradient with 10% safety factor	
Surface	1992	psig
Downhole	4294	psig
Injection Pressure @ Target rate	Expected range over project life	

Parameters/Conditions	Limit or Permitted Value	Unit
Surface Start / End / Average	1,014 /1,702 / 1358*	psig
Downhole Start / End / Average	2,082 / 4,060 / 3071*	psig
Target Injection Rate	18.75* 993	mmscfpd Tonnes/day
Maximum Injection rate	25** 1324	mmscfpd Tonnes/day
Annulus Pressure	Expected range over project life	
Surface Start / End / Average	100 / 1139 / 620	psig
Downhole Start / End / Average	3101 / 4140 / 3621	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

**Downhole and Surface pressures estimated at Target rate from Plume model and Prosper modeling respectively*
***Well only expected to be operated at maximum injection rates for short periods of time for Project flexibility*

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 5 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well 373-35R, CTV expects a maximum injection rate of 25 million standard cubic feet and a maximum injection pressure of 4294psi (90% of the fracture pressure calculated at the top perforation using a 0.71psi/ft fracture gradient). To account for fluctuations in the daily operating rates and pressure, a threshold of 10% below the maximum rate and 10% below the maximum injection pressure will be used to configure the automation and alarms, which equates to a rate threshold of 22.5 million standard cubic feet and 3865psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 165 tons per day over a 6-day period to ensure protection of health, safety, and the environment. This same procedure applies to routine shutdowns and to the gradual shutdowns described in the Attachment F – Emergency and Remedial Response plan.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and/or digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature profile, which could be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, during, and after injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV’s standard procedures. Note that ground level corresponds to 14’ MD due to the depth reference to the kelly bushing 14’ above ground level during drilling.

Table 6: Plugging details

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	6.276	6.366	6.366	6.276
Depth to bottom of tubing or drill pipe (ft)	7,871	2,529	1,097	39

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Sacks of cement to be used (each plug)	201	25	25	5
Slurry volume to be pumped (bbl)	41.17	5.12	5.12	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	6,799	2,404	972	14
Bottom of plug (ft)	7,871	2,529	1,097	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.
2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.
3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.
5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.
6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.
7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.
8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.
9. Once the fourth cement plug is placed at surface, casing will be cut 5’ below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):
    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

Monitoring Well Pre-Operational Testing

Internal Mechanical Integrity

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External Mechanical Integrity

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Cement Bond Log

Formation Testing

Corrosion Monitoring and CO2 Compatibility

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Monitoring Well Plugging Plan

Etchegoin Monitoring Well Plugging Procedure

The following plugging procedure is planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.
2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.
3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

9. Once the fourth cement plug is placed at surface, casing will be cut 5’ below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.

Monterey Monitoring Wells Plugging Procedure

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

9. Once the surface cement plug is placed, casing will be cut 5’ below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.